NON-PUBLIC?: N
ACCESSION #: 9110180042
LICENSEE EVENT REPORT (LER)

FACILITY NAME: PLANT HATCH, UNIT 1 PAGE: 1 OF 7

DOCKET NUMBER: 05000321

TITLE: TURBINE TRIP GENERATOR GROUND FAULT SIGNAL CAUSES REACTOR SCRAM
EVENT DATE: 08/09/91 LER #: 91-013-01 REPORT DATE: 10/09/91

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
50.73(a)(2)(iv)

LICENSEE CONTACT FOR THIS LER:
NAME: STEVEN B. TIPPS, MANAGER NUCLEAR TELEPHONE: (912) 367-7851
SAFETY AND COMPLIANCE HATCH

COMPONENT FAILURE DESCRIPTION:
CAUSE: X SYSTEM: FK COMPONENT: BKR MANUFACTURER: G080
REPORTABLE NPRDS: N

SUPPLEMENTAL REPORT EXPECTED: NO

ABSTRACT:

On 8/9/91 at 1523 CDT, Unit 1 was in the Run mode at a power level of 2436 CMWT (100% rated thermal power). At that time, Generator Field Ground Detecting Relay 1N51-K751 actuated causing a Main Turbine trip and reactor scram on Turbine Stop Valve (TSV) closure per design. Reactor vessel water level decreased as expected due to void collapse resulting in a Group 2 Primary Containment Isolation System signal on low water level. All Group 2 Primary Containment Isolation Valves closed per design except Drywell Equipment Drain Sump Outboard Isolation Valve 1G11-F020. This valve took 114 seconds to close; however, it is required to close within 15 seconds of the receipt of an isolation signal. Valve 1G11-F019, the inboard isolation valve for the Primary Containment penetration, closed in 11 seconds, effectively isolating the penetration in the required time frame. Reactor vessel pressure increased to about 1120 psig following closure of the TSVs. All the Safety Relief Valves

(SRVs) except 1B21-F013J opened to decrease pressure. A review of post-scram data indicated SRV 1B21-F013J behaved properly during the event. The Main Turbine Bypass Valves operated to control pressure after the SRVs closed.

The cause of this event is believed to have been a short duration ground. Post-scram testing of the generator revealed no existing ground fault. Calibration of relay 1N51-K751 indicated its trip setpoint had drifted, but spurious actuation of the relay could not be proven. The reason valve 1G11-F020 was slow to close is still under investigation.

Corrective actions include testing the generator, replacing relay 1N51-K751, and timing and scheduling an inspection of valve 1G11-F020.

END OF ABSTRACT

PLANT AND SYSTEM IDENTIFICATION

General Electric - Boiling Water Reactor
Energy Industry Identification System Codes are identified in the text as (EIIS Code XX).

DESCRIPTION OF EVENT

On 8/9/91 at 1523 CDT, Unit 1 was in the Run mode at a power level of 2436 CMWT (100% rated thermal power). At that time, Generator Field Ground Detecting Relay 1N51-K751 actuated resulting in a Main Turbine (EIIS Code TA) trip. The turbine trip, per design, caused a reactor scram on Turbine Stop Valve (TSV, EIIS Code SB) closure.

A Generator trip signal was received approximately five seconds after the Main Turbine trip as expected. Power Circuit Breaker (PCB, EIIS Code FK) 179510 in the Plant Hatch 230 kV switchyard received a trip signal and all three phases of the PCB opened as designed. PCB 179500 also received a trip signal, but Phase 2 of this PCB did not open. Phases 1 and 3 opened as required. Approximately 21 minutes into the event, a substation electrician manually tripped PCB 179500 which caused Phase 2 to open. No equipment damage resulted from nor were scram recovery actions made more difficult by PCB 179500 Phase 2 not opening on the original trip signal.

Following the reactor scram, reactor vessel water level decreased from its normal level of 36 inches (as measured from instrument zero, 200 inches above the top of the active fuel). This is an expected occurrence caused by void collapse from the rapid decrease in power. Level decreased to a minimum of 7 inches about four seconds after the scram. This reduction in reactor water level below the level 3 setpoint of 10 inches resulted in another reactor scram signal and a Group 2 Primary Containment Isolation System (PCIS, EIIS Code JM) signal. The two Reactor Feedwater Pumps (EIIS Code SJ) automatically restored water level to normal within four minutes of the scram. No Emergency Core Cooling Systems actuated nor were any required to actuate to restore and/or maintain water level.

All Group 2 Primary Containment Isolation Valves (PCIVs, EIIS Code JM) closed per design except Drywell Equipment Drain Sump Outboard Isolation Valve 1G11-F020. This valve took 114 seconds to close. Unit 1 Technical Specifications Table 3.7-1 requires the valve to close within 15 seconds of the receipt of an isolation signal. Valve 1G11-F019, the inboard isolation valve for the Primary Containment penetration, closed in 11 seconds, effectively isolating the penetration in the required time frame.

Reactor vessel pressure increased to a peak value of approximately 1120 psig five seconds after the scram. The Main Turbine Bypass Valves (BPV, EIIS Code SO) and all the Safety Relief Valves (SRVs, EIIS Code SB) except 1B21-F013J opened to decrease pressure. The Low Low Set (LLS, EIIS Code JE) system logic actuated as required when the first SRV lifted at its mechanical lift setpoint. The BPVs, the Low Low Set SRVs, and the other SRVs which opened operated as designed and closed as reactor pressure decreased. Reactor pressure was then controlled by the BPVs.

A post-scram review of the data indicated SRV 1B21-F013J behaved properly during the event given the peak reactor vessel pressure seen. Pressure instruments 1B21-R004A and B recorded peak event pressures of 1115 psig and 1125 psig, respectively. Engineering and Instrument and Control supervisory personnel calculated a head correction factor of 14 psig for these instruments. Additionally, General Electric, in a letter dated 2/12/91, determined that "the pressure difference between the reactor vessel (where the pressure readings are taken) and the steam line can be as high as 10 psi." Subtracting the head correction factor and the pressure drop from the readings of pressure instruments 1B21-R004A and B yields pressure at the SRV of 1091 psig and 1101 psig, respectively. The nominal setpoint for SRV 1B21-F013J is 1100 psig with a Unit 1 Technical Specification allowed tolerance of plus or minus 11 psig (plus or minus 1%). Therefore, it was concluded that the pressure of 1101 psig at the SRV was not sufficient to lift it given its maximum allowable lift setpoint of 1111 psig. On 8/12/91 with the reactor vessel at rated pressure, SRV 1B21-F013J was manually opened to verify it was not stuck closed.

CAUSE OF EVENT

The cause of this event is believed to have been a short duration ground in the generator or its ground fault detection protective relaying. Post-scram testing of the generator after the generator field brushes had been removed revealed no existing ground fault. The resistance reading was found to be 150 megohms versus a minimum acceptable value of 10 megohms. The ground circuit that energizes the ground detecting relay was checked also. No ground was found with the generator field brushes. Finally, the positive and negative brush riggings were checked at the generator for grounds. None were found.

The fact that no ground faults were found during post-scram testing does not conclusively prove that a ground fault did not exist at the time of the scram. The ground path may have been intermittent. It may have been in the generator field brushes and, thus, removed when the brushes were removed. The ground path may have been some dust or dirt which was burned up by the heat of the ground current or shaken loose by the vibration of the turbine-generator from the turbine trip. Post-scram testing would not have revealed a ground resulting from any of these possible causes.

Following the event, Generator Field Ground Detecting Relay 1N51-K751 was calibrated per plant procedure 57CP-CAL-124-1S, "General Electric Ground Detection Relays PJG and YA122." It was found the relay would trip at a lower ground fault current than required. Further, it was found that the trip point was not repeatable, i.e., the relay would not trip repeatedly at the same test current. No other problems were found with the relay.

The above described relay problems do not conclusively prove that it actuated spuriously or incorrectly. As stated previously, there may have been a ground present to actuate the relay. The relay's trip setpoint drift (from 500 ohms to 1900 ohms) is insignificant when compared to the generator's minimum required resistance to ground of 10 megohms. Therefore, the setpoint drift should not have had any affect on this event. It also should be noted the relay had a ten-second time delay to help prevent spurious actuations. The time delay was found to be within procedural tolerances, making spurious actuation of the relay unlikely as the cause of this event.

The reason valve 1G11-F020 was slow to close has not yet been determined.

Subsequent stroking of the valve from the Main Control Room using its remote manual switch showed it would close in about six seconds. (Its maximum allowable stroke time is 15 seconds.) This is an air operated valve; therefore, it is possible that the air exhaust port on the solenoid operated valve actuator was partially clogged or sticking in the closed position. This would have prevented the air pressure from exhausting quickly enough to allow the valve to close within the required time frame. The initial valve actuation may have been sufficient to unclog or unstick the exhaust port thereby explaining the subsequent acceptable stroking of the valve. The valve will be inspected during the upcoming refueling outage in an attempt to determine the cause for its excessive closing time.

The cause of Phase 2 of PCB 179500 not opening was component failure. The armature of the control valve for PCB 179500 was rusted to the frame for the control coil. This prevented the control valve from opening PCB 179500 Phase 2 upon receipt of a trip signal. The armature broke free when 510 psig air was supplied to the control valve through the manual trip air line when the PCB was manually tripped.

REPORTABILITY ANALYSIS AND SAFETY ASSESSMENT

This report is required by 10 CFR 50.73(a)(2)(iv) due to the unplanned actuation of the Reactor Protection System (RPS, EIIS Code JC) and the PCIS, Engineered Safety Feature Systems. The RPS actuated per design when the TSVs closed on a trip of the Main Turbine from actuation of Generator Field Ground Detecting Relay 1N51-K751. This relay provides a direct input to the turbine trip logic. Additionally, a Group 2 PCIS isolation signal was received on low reactor vessel water level caused by void collapse from the rapid reduction in power. One of the Group 2 PCIVs, 1G11-F020, did not function properly in that it failed to close within its required time frame. The redundant isolation valve in the line did close within the required time which resulted in the Primary Containment penetration being isolated in a timely m
nner.

The RPS automatically initiates a reactor scram to ensure the radioactive materials barriers, such as the fuel cladding and pressure system boundary, are maintained and to mitigate the consequences of transients and accidents. Closure of the TSVs, such as occurs on a turbine trip, can result in the addition of positive reactivity to the core as the resultant reactor pressure increase collapses voids. Therefore, TSV closure initiates a scram prior to high neutron flux or high reactor pressure signals to provide a satisfactory margin to core thermal-hydraulic limits. The high-pressure scram, in conjunction with the pressure relief system, is adequate to preclude overpressurizing the pressure system boundary; however, the TSV closure scram provides additional margin.

The PCIS provides timely protection against the onset and consequences of events involving the potential release of radioactive materials from the fuel and nuclear system process barriers by isolating, generally by the closure of two series and redundant isolation valves, appropriate lines which penetrate the Primary Containment. Isolation of Group 2 PCIVs, initiated by a low reactor vessel water level condition, prevents the escape of radioactive materials from the Primary Containment through process lines which may have been breached. Additionally, isolation of these process lines conserves reactor coolant inventory if a breach of one of these lines caused the low water level condition.

In this event, the TSVs closed on a turbine trip caused by the actuation of relay 1N51-K751. The RPS actuated on TSV closure, per design, resulting in a reactor scram. Reactor vessel water level decreased as expected due to void collapse causing another RPS actuation and a Group 2 PCIS isolation signal on low reactor vessel water level. The Reactor Feedwater Pumps responded per design to limit the drop in water level and to recover it to and maintain it at normal levels. At no time was water level less than 171 inches above the top of the active fuel. No Emergency Core Cooling Systems actuated nor were any required to actuate to restore or maintain water level.

All Group 2 PCIVs closed per design except valve 1G11-F020. This valve took 99 seconds longer to close than allowed by Unit 1 Technical Specifications Table 3.7-1. However, this valve is in series with PCIV 1G11-F019 which did close within the allowable time. Because the two valves are in series and are designed to be redundant isolation valves, the Primary Containment penetration was completely isolated by PCIV 1G11-F019 in a timely manner.

Based on the above discussion, it is concluded that this event had no adverse impact on nuclear safety. This analysis is applicable to all power levels.

CORRECTIVE ACTION

The generator was checked for ground faults. None were found.

Relay 1N51-K751 was replaced because its trip setpoint was not repeatable during calibration.

Valve 1G11-F020 was stroked and timed in the close direction on 8/9/91, approximately 5 1/2 hours after the scram. It closed in six seconds, well within the 15 seconds required by Unit 1 Technical Specifications. However, an Operating Order was put in place requiring that the valve be stroked and timed in the close direction on a weekly basis until the beginning of the refueling outage on 9-18-91. It was believed that the more frequent testing (normally it is stroked and timed once per quarter) would help insure the valve's performance was not degrading and the solenoid would continue to operate freely until it could be inspected. This was done with the valve being successfully stroked each time.

Valve 1G11-F020 will be inspected under Maintenance Work Order 1-91-4693 during the ongoing refueling outage. Additional corrective actions will be taken as warranted based on the results of the inspection.

PCB 179500 was disassembled and inspected by Georgia Power Company and General Electric personnel. The control valve armature was found rusted to the control coil frame. Per instructions from the vendor, General Electric, the rust was removed from the Phase 2 control valve armature and frame by glass bead blasting. The individual parts were then primed and painted. The other two phases' control valve armature and control coil frame were also cleaned, primed, and painted. The PCB was then reassembled and tested successfully.

Other PCBs of this type in the Plant Hatch switchyard will be inspected during their next preventive/diagnostic inspection to ensure the control coil frame and armature are painted. If not, they will be cleaned, primed, and painted.

ADDITIONAL INFORMATION

No systems other than those previously mentioned were affected by this event.

Failed Components Information:

Master Parts List Number: PCB 179500
Manufacturer: General Electric
Model Number: ATB-242-7AY
Type: Power Circuit Breaker
Manufacturer Code: G080
EIIS System Code: FK
Reportable to NPRDS: No
Root Cause Code: X

EIIS Component Code: BKR

There have been no previous similar events in the last two years in which a generator ground signal caused a turbine trip and reactor scram.

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There has been one previous similar event reported in the last two years in which Phase 2 of PCB 179500 failed to open upon receipt of an automatic trip signal. That event was reported in LER 50-321/1991-001 dated 2/11/91. In that event, it was thought that a failed current limiting resistor in the PCB's control circuit prevented the trip signal from reaching Phase 2. Following repair of the control circuitry the PCB was cycled successfully several times. The PCB itself was not disassembled because it appeared the cause of the failure of Phase 2 to open had been found in the failed resistor. Upon a more detailed investigation following the 8/9/91 event, it was found the current limiting resistor failed as reported in LER 50-321/1991-001 because of excessive current through the trip circuit when the phase failed to open to clear the fault. In fact, both failures of the phase to open were apparently caused by the armature being rusted to the control coil frame which prevented the pneumatic control valve from operating. The PCB cycled freely once the armature was broken free of the frame, but became stuck again by the time the 8/9/91 event occurred.

ATTACHMENT 1 TO 9110180042 PAGE 1 OF 2

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J. T. Beckman, Jr.
Vice President-Nuclear
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October 9, 1991

U.S. Nuclear Regulatory Commission

ATTN: Document Control Desk
Washington, D.C. 20555

PLANT HATCH - UNIT 1
NRC DOCKET 50-321
OPERATING LICENSE DRP-57
LICENSEE EVENT REPORT
TURBINE TRIP ON GENERATOR GROUND
FAULT SIGNAL CAUSES REACTOR SCRAM

Gentlemen:

In accordance with the requirements of 10 CFR 50.73(a)(2)(vii), Georgia Power Company is submitting the enclosed revision to a Licensee Event Report (LER) concerning a turbine trip on a generator ground fault signal which resulted in a reactor scram. This event occurred at Plant Hatch - Unit 1.

Sincerely,

J. T. Beckman, Jr.

OCV/cr

Enclosure: LER 50-321/1991-013, Revision 1

cc: (See next page.)

ATTACHMENT 1 TO 9110180042 PAGE 2 OF 2

Georgia Power

U.S. Nuclear Regulatory Commission
October 9, 1991
Page Two

cc: Georgia Power Company
Mr. H. L. Sumner, General Manager - Nuclear Plant
NORMS

U.S. Nuclear Regulatory Commission, Washington, D.C.
Mr. K. Jabbour, Licensing Project Manager - Hatch

U.S. Nuclear Regulatory Commission, Region II
Mr. S. D. Ebneter, Regional Administrator
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